

BEFORE THE
PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

PUBLIC UTILITIES
COMMISSION

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In the Matter of the Application of)
HAWAIIAN ELECTRIC COMPANY, INC.)
For Approval of Rate Increases and)
Revised Rate Schedules and Rules)

DOCKET NO. 2008-0083

DIRECT TESTIMONY AND EXHIBITS OF MAURICE BRUBAKER
ON BEHALF OF THE DEPARTMENT OF DEFENSE.

AND

CERTIFICATE OF SERVICE

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COMES NOW, DEPARTMENT OF DEFENSE by and through its undersigned attorney and
hereby submits its Direct Testimony and Exhibits of Maurice Brubaker to Hawaiian Electric Company,
Inc.

DATED: Honolulu, Hawaii, April 28, 2009.


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Direct Testimony and Exhibits of

Maurice Brubaker

On behalf of

Department of Defense

April 28, 2009



BRUBAKER & ASSOCIATES, INC.
CHESTERFIELD, MO 63017

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Direct Testimony of Maurice Brubaker

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140,
3 Chesterfield, MO 63017.

4 **Q. WHAT IS YOUR OCCUPATION?**

5 A. I am a consultant in the field of public utility regulation and president of Brubaker &
6 Associates, Inc. (BAI), energy, economic and regulatory consultants.

7 **Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

8 A. I have been involved in the regulation of electric utilities, competitive issues and
9 related matters over the last three decades. Additional information is provided in
10 Appendix A, attached to this testimony.

11 **INTRODUCTION AND SUMMARY**

12 **Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?**

13 A. BAI is under contract with the United States Department of the Navy, Utility Rates and
14 Studies Office, to perform utility cost allocation, cost of service, rate design and other
15 special studies. The Navy represents the Department of Defense (DOD) and all other
16 Executive Agencies of the Federal Government in certain assigned geographical
17 areas. The DOD installations on Hawaii are major purchasers of electricity from
18 Hawaiian Electric Company (HECO), and most of DOD's electricity is purchased
19 under the PT and PP rate schedules.

1 Q. WHAT SUBJECTS ARE ADDRESSED IN YOUR TESTIMONY?

2 A. My testimony addresses class cost of service, revenue allocation and rate design
3 issues. I also address the Energy Cost Adjustment Clause (ECAC) and HECO's
4 power factor study. Other witnesses appearing for the DOD will address cost of
5 capital and accounting issues.

6 Q. DOES THE REVENUE REQUIREMENT WHICH YOU HAVE USED FOR
7 PURPOSES OF YOUR COST OF SERVICE, REVENUE ALLOCATION AND RATE
8 DESIGN ANALYSIS TAKE INTO ACCOUNT ADJUSTMENTS PROPOSED BY
9 OTHER DOD WITNESSES?

10 A. No, it does not. For ease of comparison and to illustrate costing and rate design
11 principles, I have utilized the revenue requirement claims that have been made by
12 HECO. Use of those numbers is strictly for that purpose, and should not be
13 interpreted as an endorsement of HECO's claims. All adjustments found appropriate
14 by the Commission should be incorporated into the cost of service study.

15 Q. HAVE YOU BASED YOUR ANALYSIS ON HECO'S UPDATE FILING?

16 A. Yes.

17 **CONCLUSIONS AND RECOMMENDATIONS**

18 Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS?

19 A. My conclusions and recommendations may be summarized as follows:

20 1. The embedded cost methodology employed by HECO is generally consistent with
21 industry practice and is suitable for use in this proceeding.

2. The HECO class cost of service study that incorporates the minimum system method for classifying distribution costs is reasonable.
3. The alternative study submitted by HECO as a result of the stipulation in the last rate case does not recognize the minimum system component in the distribution system; therefore is unreasonable and should not be utilized for any purpose.
4. The proposed across-the-board increase does not move classes closer to cost of service; instead, it moves all the major classes further away from cost.
5. The Commission should direct that the rate increase resulting from this proceeding be allocated in such a way that it meaningfully reduces existing interclass subsidies.
6. HECO's proposal to establish a rate for directly served customers, Rate DS, is reasonable and should be adopted by the Commission.
7. HECO's proposed Schedule P is reasonable.
8. The study HECO presented to develop the cost associated with power factor correction is unreliable and should not be relied upon. However, HECO's proposal not to change the current power factor charges is reasonable, in light of the lack of an appropriate study.

GENERAL CONCEPTS AND PRINCIPLES

- Q. PLEASE DESCRIBE THE GENERAL PRINCIPLES AND PROCEDURES THAT SHOULD BE FOLLOWED IN COST OF SERVICE, REVENUE ALLOCATION AND RATE DESIGN.**
- A.** Cost of service includes the total of the directly assignable costs plus the appropriately allocated share of the other costs that go to each customer class. It also encompasses the rate design, requiring that to the extent possible the elements of the rate structure (i.e., customer, demand and energy charges) should reflect costs.

1 Q. PLEASE BRIEFLY SUMMARIZE WHY YOU BELIEVE IT IS IMPORTANT THAT
2 THE ALLOCATION OF REVENUE REQUIREMENTS TO CLASSES AND THE
3 DESIGN OF RATES BE BASED ON COST.

4 A. The use of cost as a basis for allocating the total revenue requirement among classes
5 is critical for three reasons. First, it is the only objective definition of basic fairness.
6 The premise is that each customer should pay costs associated with its consumption,
7 but not that of others. Because designing individual rate schedules for each
8 customer is not practical, it is necessary to group customers into classes. Therefore,
9 the first step is to ensure that each customer pays only costs associated with its own
10 purchases and that the revenue requirement of the class follows this same principle.

11 Second, if the allocation of revenues to classes departs from cost, efficiency
12 suffers. Class revenues are used as the basis for designing the specific rates that
13 provide critical information to customers about the cost consequences of their
14 purchase decisions. If these signals are distorted because the rates are designed on
15 class revenues that are not closely related to class costs, customers will make
16 inefficient choices concerning their use of resources (not just electricity, but
17 competing energy sources such as gaseous fuels, wind and solar and energy
18 efficiency options). The resulting inefficient use of resources is a bad outcome for the
19 customer, the utility, the state of Hawaii and society in general.

20 Third, an allocation of revenues to classes that is not based on cost will result
21 in revenue instability for the utility. The utility will only recover the test year revenue
22 requirement from a class if the actual billing units happen to exactly equal those
23 estimated for the test year. If class revenues and rates track costs, then changes in
24 class revenues and costs will move in step when actual consumption differs from test
25 year consumption, and the utility will remain stable. If, however, the revenue

1 requirement of a particular class is less than cost and that class grows relative to the
2 test year assumptions, the result will be a revenue shortfall for the utility, which will
3 lead to additional rate case filings and potentially higher rates for all customers.

4 For many of the same reasons, the design of the customer, demand and
5 energy charges within each tariff should also be guided by cost of service. This is
6 appropriate not only to charge customers the appropriate share of costs, but also to
7 give customers the proper price signal so they can make informed and rational
8 decisions.

9 **Q. WHAT KIND OF CLASS COST OF SERVICE STUDIES DID HECO FILE?**

10 **A.** HECO filed an embedded cost of service study and a marginal cost of service study.

11 **Q. ARE THERE FUNDAMENTAL DIFFERENCES BETWEEN THE TWO KINDS OF**
12 **STUDIES?**

13 **A.** Yes. An embedded cost of service study allocates the costs which a utility actually
14 incurs to provide service (based on an historic period or, as in this case, a projected
15 test year) to customer classes based on factors that reflect how customers cause the
16 utility to incur costs.

17 A marginal cost study, on the other hand, does not represent the utility's
18 actual costs or revenue requirement and cannot be calculated in a straightforward
19 manner. It is an estimate of the cost to serve "one more" customer, "one more"
20 kilowatt (kW) of demand or "one more" kilowatthour (kWh) of energy. In addition, if
21 marginal costs are calculated for each customer class, and then added together, the
22 sum of these costs will not equal the utility's revenue requirement. Therefore, even
23 after marginal costs are calculated, a process must be developed to reconcile these

1 calculated marginal costs to the utility's revenue requirement – otherwise setting rates
2 equal to calculated marginal cost would produce an under-recovery of revenues or an
3 over-recovery of revenues.

4 **Q. WHAT IS THE PREFERABLE APPROACH TO DETERMINING CLASS COST OF**
5 **SERVICE?**

6 A. An embedded cost of service study is the appropriate approach. It is a reflection of
7 costs actually incurred, not a theoretical construct based on the cost of serving "one
8 more" customer, kW or kWh.

9 **Q. HOW DO YOU ADDRESS THE THEORETICAL ARGUMENTS THAT SOME**
10 **WOULD SAY SUPPORT THE USE OF MARGINAL COSTS OVER EMBEDDED**
11 **COSTS?**

12 A. The underpinning of the theoretical justification for the use of marginal cost is the
13 assumption that all other goods and services in the economy are priced at their
14 respective marginal cost. This obviously is a situation which is unlikely to exist.
15 Furthermore, the marginal costs consistent with economic theory are the marginal
16 "social" costs and not the real world economic costs. Social costs would, for
17 example, exclude income taxes, which simply are transfer payments and not resource
18 costs. Thus, the economic justification for marginal cost pricing exists only in theory.

19 **Q. WHAT IS YOUR RECOMMENDATION?**

20 A. Based on these considerations I recommend that the Commission utilize HECO's
21 embedded class cost of service study as the basis for determining class revenue
22 requirements.

HECO'S EMBEDDED COST OF SERVICE STUDY

**Q. HAVE YOU REVIEWED HECO'S EMBEDDED CLASS COST OF SERVICE STUDY
AS PRESENTED BY WITNESS PETER YOUNG?**

A. Yes, I have.

**Q. DO YOU HAVE ANY OVERALL COMMENTS WITH RESPECT TO HECO'S
EMBEDDED CLASS COST OF SERVICE STUDY?**

A. Yes. In general, the HECO class cost of service study that incorporates the minimum system method for classifying distribution costs is reasonable. I have reviewed the principal separations of costs between fixed and variable and the fixed costs between demand-related and customer-related costs. These are reasonable and consistent with general industry practice. The alternative study (produced in accordance with the stipulation in the last case), which treats the distribution system costs as demand-related, is not reasonable and should not be relied upon. I elaborate on the problems with this study later in my testimony.

Basic Steps in a Cost of Service Study

**Q. PLEASE BRIEFLY DESCRIBE THE STEPS OF FUNCTIONALIZATION,
CLASSIFICATION AND ALLOCATION.**

A. Functionalization refers to the grouping of costs into the major aspects of a utility's operation; namely, production, transmission, distribution, customer and general. Classification refers to the identification of the functionalized costs as being demand-related, energy-related or customer-related in nature.

1 Allocation refers to the development of factors to be applied to the various revenue
2 requirement elements (after they have been functionalized and classified) in order to
3 develop the cost of serving each of the various customer classes.

4 **Q. PLEASE DEFINE DEMAND, ENERGY, AND CUSTOMER, AS THESE TERMS**
5 **APPLY TO ELECTRIC UTILITY COST OF SERVICE.**

6 A. Demand is analogous to speed, which measures how fast one is traveling. Likewise,
7 a customer's demand indicates the rate of energy consumption; that is, how much
8 energy is being consumed at that moment. Demand is an extremely important
9 concept in electric utility operations because it establishes the size of the production
10 facilities (or purchased power capacity), as well as the size of the transmission and
11 distribution facilities that must be provided to meet customer demands at the instant
12 that they arise.

13 Energy-related costs are those which basically vary with the number of kWh
14 sold, such as the fuel and other variable components of purchased power cost.
15 Whereas demand is analogous to the speed or rate of travel, energy is analogous to
16 the distance traveled.

17 Customer-related costs are those which are incurred simply as a
18 consequence of serving a customer, irrespective of the demand imposed and the
19 amount of energy consumed. Examples are the cost of meters, service drops, and
20 customer meter reading, billing and accounting expenses. Also, a significant portion
21 of the distribution system is required simply to make power available throughout the
22 utility's service territory, regardless of the level of demands, and is therefore con-
23 sidered customer-related.

1 Q. IS THIS COST OF SERVICE APPROACH WHICH YOU HAVE DESCRIBED USED
2 THROUGHOUT THE ELECTRIC UTILITY INDUSTRY?

3 A. Yes. Every logic based cost analysis must use the procedures of functionalization,
4 classification, and finally, allocation to classes.

5 **Customer-Related and Demand-Related Costs**

6 Q. PLEASE ELABORATE FURTHER ON THE DISTINCTION BETWEEN
7 CUSTOMER-RELATED COSTS AND DEMAND-RELATED COSTS IN THE
8 CONTEXT OF A CLASS COST OF SERVICE STUDY.

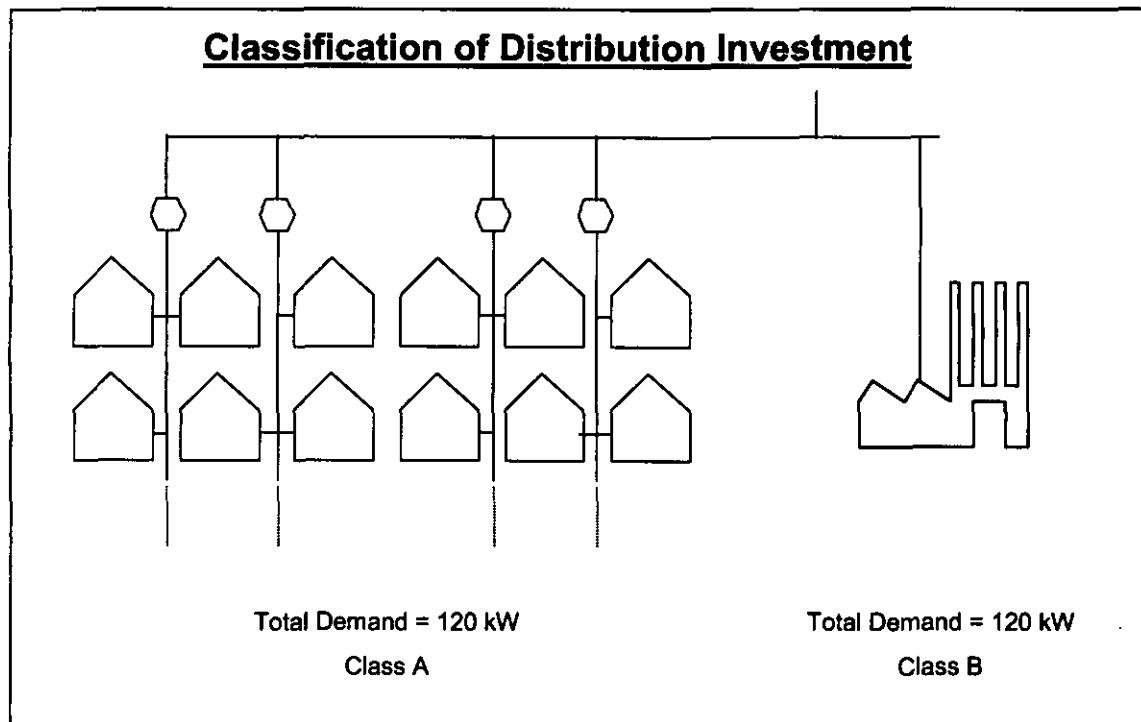
9 A. A certain portion of the cost of the distribution system—poles, wires and transformers—
10 is required just to attach customers to the system, regardless of their demand or
11 energy requirements. This minimum or "skeleton" distribution system may also be
12 considered a customer-related cost since it depends primarily on the number of
13 customers, rather than on demand or energy usage.

14 Figure 1, as an example, shows the distribution network for a utility with two
15 customer classes, A and B. The physical distribution network necessary to attach
16 Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a
17 total demand of 120 kW. This is the same total demand as is imposed by Class B,
18 which consists of a single customer. Clearly, a much more extensive distribution
19 system is required to attach the multitude of small customers (Class A), than to attach
20 the single larger customer (Class B), despite the fact that the total demand of each
21 customer class is the same.

22 Even though some additional customers can be attached without additional
23 investment in some areas of the system, it is obvious that attaching a large number of

customers requires investment in facilities, not only initially but on a continuing basis as a result of the need for maintenance and repair. Thus, a large part of the distribution system is classified as customer-related in order to recognize this area coverage requirement.

Figure 1



Q. IN ADDITION TO THE AREA COVERAGE FACTOR YOU NOTED ABOVE, ARE THERE OTHER REASONS FOR CLASSIFYING PART OF THE DISTRIBUTION SYSTEM AS CUSTOMER-RELATED?

A. Yes, there are. Safety and reliability are the best example of these. A properly conducted class cost of service study must consider all cost-causing factors.

1 **Q. PLEASE EXPLAIN.**

2 **A.** When distribution engineers design the enhancement, upgrade, or extension of an
3 electric system, they must be constantly aware of the operating parameters of the
4 system. It is in the construction of the distribution system, however, that the *true*
5 *cause* of many distribution costs is clearly seen. Surprisingly, that cause is frequently
6 not demand.

7 An illustration helps make this point clear. Consider a customer who intends
8 to build a home on a new lot, one that does not already have electrical service. This
9 customer is cost and energy conscious and thus chooses to employ as many energy
10 efficiency techniques and appliances as he can. After considerable research and
11 consultation with experts, the customer calls the utility and advises that he will require
12 service capable of providing a maximum peak demand of 2,000 watts (2 kW).

13 During the installation of the primary and secondary distribution extension to
14 the customer's home, he notices that the linemen are using conductors, poles,
15 cross-arms, and components identical to those serving the much larger, and less
16 efficient, houses down the street. After more investigation, the customer learns that
17 the distribution extension to his home is capable of carrying far greater demand than
18 his home was designed to use. When he informs the utility of this 'error,' the utility
19 explains that because of reliability and safety concerns it cannot install wires smaller
20 than a certain size or hang them below a certain height. In short, there are specified
21 minimum standards that the utility must meet that are wholly unrelated to the new
22 home's reduced demand.

23 This illustration demonstrates that although utilities design and install
24 distribution equipment to satisfy their customers' need for electricity, there are factors
25 other than electrical demand that force them to incur costs. Safety and reliability are

1 as critical to every phase of design and construction as demand. As one reviews the
2 cost of the distribution system nearest the customer (i.e., that portion from the primary
3 radial lines through the line transformers and secondary system), the cost incurred to
4 comply with safety and reliability standards begins to outweigh the cost of meeting
5 electrical demand.

6 **Q. CAN YOU CITE ANY AUTHORITATIVE PUBLICATIONS THAT SUPPORT**
7 **ALLOCATING PART OR ALL OF PLANT ACCOUNTS 364 THROUGH 370 ON**
8 **THE BASIS OF A CUSTOMER COMPONENT?**

9 **A** Yes. In 1992 the National Association of Regulatory Utility Commissioners
10 ("NARUC") published an Electric Utility Cost Allocation Manual ("NARUC Manual").

11 The NARUC Manual states the following:

12 "Distribution Plant Accounts 364 through 370 involve demand and
13 customer costs. The customer component of distribution facilities is
14 that portion of costs which varies with the number of customers. Thus,
15 the number of poles, conductors, transformers, services, and meters
16 are directly related to the number of customers on the utility's system.
17 As shown in Table 6-1, each primary plant account can be separately
18 classified into a demand and customer component. Two methods are
19 used to determine the demand and customer components of
20 distribution facilities. They are, the minimum-size-of-facilities method,
21 and the minimum-intercept cost (zero-intercept or positive-intercept
22 cost, as applicable) of facilities." (NARUC Manual, page 90)

23 Table 6-1 from the NARUC Manual is included as Figure 2. It shows that Distribution
24 Plant Accounts 364 through 368, which include conductors and support structures,
25 have both a demand component and a customer component.

Figure 2

TABLE 6-1			
CLASSIFICATION OF DISTRIBUTION PLANT ¹			
FERC Uniform System of Accounts No.	Description	Demand Related	Customer Related
	Distribution Plant ²		
360	Land & Land Rights	X	X
361	Structures & Improvements	X	X
362	Station Equipment	X	-
363	Storage Battery Equipment	X	-
364	Poles, Towers, & Fixtures	X	X
365	Overhead Conductors & Devices	X	X
366	Underground Conduit	X	X
367	Underground Conductors & Devices	X	X
368	Line Transformers	X	X
369	Services	-	X
370	Meters	-	X
371	Installations on Customer Premises	-	X
372	Leased Property on Customer Premises	-	X
373	Street Lighting & Signal Systems ¹	-	-

¹Assignment or "exclusive use" costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components.

²The amounts between classification may vary considerably. A study of the minimum intercept method or other appropriate methods should be made to determine the relationships between the demand and customer components.

1 **Reasons for Differences in Cost of Service**

2 Q. DOES THE APPLICATION OF THE COSTING PRINCIPLES THAT YOU HAVE
3 DISCUSSED RESULT IN DIFFERENCES IN THE PER UNIT COST OF SERVING
4 DIFFERENT TYPES OF CUSTOMERS?

5 A. Yes. Typically, large users, such as those taking service on Schedules PT and PP,
6 are less costly to serve than other customers because of differences in:

7 1. level on the system where the customer is served;

1 2. load factor; and

2 3. size.

3 These differences are evident in HECO's cost of service studies.

4 **Q. WHAT IS THE LEVEL ON THE SYSTEM WHERE THE CUSTOMER IS SERVED**
5 **AND HOW DOES IT AFFECT COST OF SERVICE?**

6 A. The system level at which service is provided refers to where on the system the
7 customer is electrically and physically located. Rate PT customers take service from
8 the high voltage transmission system through substations that they own. This means
9 that HECO must invest only in the generation system and the transmission lines and
10 bulk substations. Other customers take service at lower voltage levels, which may
11 require such additional investment as distribution step-down substations, primary
12 lines; secondary transformers, and secondary lines.

13 When power is delivered at a high voltage level HECO avoids making the
14 investment in the lower voltage distribution system facilities that are required to serve
15 other customers. And, the higher the voltage level the lower the losses incurred in
16 moving the power from the generator to the customer because of the lesser number
17 of transformations involved and the shorter distances. This also reduces the cost of
18 providing the service.

19 I will discuss this issue in more detail when I address the design of the "P"
20 group of rate schedules.

21 **Q. WHAT IS LOAD FACTOR AND HOW DOES IT AFFECT COST OF SERVICE?**

22 A. Load factor measures the intensity of use of the demand placed on the system. It is
23 the ratio between the kilowatthours actually used and the kilowatthours that would

1 have been used had the maximum demand been experienced during the entire year.
2 Customers with a steady use will have a high load factor, while customers with erratic
3 loads or seasonal or daily variations will have a lower load factor. A customer with a
4 high load factor makes much more efficient use of the capacity which is required to
5 meet the maximum demands, and therefore permits the fixed costs to be spread over
6 more kilowatthours of output. This has the effect of reducing the per unit cost of
7 service.

8 **Q. HOW DOES SIZE AFFECT COST OF SERVICE?**

9 A. Customer size affects cost of service by allowing costs which are relatively fixed—such
10 as meter reading, billing and postage—to be spread over more kilowatthour sales,
11 thereby reducing the per unit cost.

12 In addition, large customers typically are served from large transformers and
13 the investment cost associated with large transformers, per unit of capability, is
14 generally less than the cost per unit of capability associated with small transformers.
15 Thus, customer size produces certain economies in these facilities, and thereby
16 reduces cost of service.

17 **Allocation of Generation Costs**

18 **Q. WHAT ARE THE MOST INFLUENTIAL ALLOCATORS IN A CLASS COST OF**
19 **SERVICE STUDY?**

20 A. The most influential allocators, in terms of affecting the results, are the allocation of
21 fuel and other energy-related costs, and the allocation of fixed costs associated with
22 the generation and transmission systems.

1 HECO has allocated the fuel, variable purchased power charges and other
2 variable costs using class energy consumption, adjusted for losses to the level of
3 service at which each customer class receives electricity.

4 The fixed costs associated with the generation and transmission system have
5 been allocated to classes using what is known as the average and excess demand
6 allocation methodology (AED). As Mr. Young explains, under this methodology class
7 average demands and class maximum demands are taken into account. The
8 allocation factor has two components. The first component is the average demand of
9 each class. The second component is the difference between the maximum demand
10 of a class and its average demand. The average component is given a weighting
11 equal to the utility system load factor, and the excess component is given a weighting
12 equal to one minus the system load factor.

13 **Q. IS THIS AED METHODOLOGY APPROPRIATE FOR THE HECO SYSTEM?**

14 **A.** Yes. The HECO system has a relatively high load factor, a relatively low seasonality
15 (which means that there are not pronounced differences among the peak demands
16 for the 12 months of the year), and a fairly broad peak on the peak days (meaning
17 that loads are at or near the maximum demand for an extended period of time on the
18 day of the monthly system peak). Given these load characteristics the AED allocation
19 methodology continues to be appropriate for the HECO system.

COST OF SERVICE RESULTS

HECO's Proposed Increase

Q. WHAT IS SHOWN ON EXHIBIT DOD-302?

A. This exhibit shows how HECO has proposed to allocate its proposed revenue increase. Column (1) shows the revenues under the currently effective rates, which are the rates in effect as a result of the revised interim increase granted in June 2008 in Docket No. 2006-0386. Column (2) shows the proposed dollar increase and column (3) shows the percentage increase. Essentially, Exhibit DOD-302 shows that HECO has proposed an equal percentage increase (5.37%) over these currently effective rates.

Q. IS AN EQUAL PERCENTAGE INCREASE APPROPRIATE?

A. No. To understand why, please refer to Exhibit DOD-303. This exhibit shows the results of HECO's cost of service study at currently effective rates. In addition to the information shown in HECO's cost of service exhibits and workpapers, I have added a column (7), which is called "subsidy."

Subsidies

Q. WHAT DOES THE SUBSIDY REPRESENT?

A. The subsidy indicates the revenue dollars by which a rate schedule deviates from the level required to produce the system average rate of return, or in other words, to pay its cost of service, no more and no less.

A negative number means that a class is below its cost of service, while a positive number indicates that a class is above its cost of service. With the exception

1 of the relatively small Schedule F, only the residential class (Schedule R) is
2 significantly below cost. Considering these significant differences from cost, an
3 across-the-board increase simply is not appropriate because it will not move rates
4 closer to cost and, in fact, exacerbates existing subsidies.

5 **Q. CAN YOU ILLUSTRATE?**

6 A. Yes. Please refer to Exhibit DOD-304. Calculations on this exhibit are similar to
7 those on Exhibit DOD-303, except that all the numbers relate to the cost of service
8 results at HECO's proposed rates which are derived by application of an equal
9 percentage or across-the-board increase to all classes.

10 **Q. WHAT MOVEMENTS TOWARD OR AWAY FROM COST OF SERVICE ARE**
11 **PRODUCED BY THIS ACROSS-THE-BOARD ALLOCATION?**

12 A. Please refer to Exhibit DOD-305. Columns (1) and (2) show the subsidies at present
13 rates and at HECO's proposed rates, respectively, and are taken from the two
14 preceding exhibits. Column (3) shows the amount of change in the subsidy, and
15 column (4) shows the direction of change. Only Schedules G and J move closer to
16 cost. All of the other classes move further away from cost. Schedules R and F are
17 further below cost with the across-the-board increase. All of the other schedules
18 which are above cost, namely DS and P, move further above cost.

1 Q. HAVE YOU CALCULATED HOW HECO'S PROPOSED INCREASE WOULD NEED
2 TO BE ALLOCATED IN ORDER TO MAKE SOME MEANINGFUL MOVEMENT
3 TOWARD COST OF SERVICE?

4 A. Yes, I have. Exhibit DOD-306 shows how HECO's proposed increase would need to
5 be distributed in order to move each class 100% of the way to cost of service. In
6 other words, to reduce the existing subsidies to zero, rather than to increase them
7 significantly. As compared to an overall average increase of 5.37%, class increases
8 would range from approximately no increase (Schedule P) to 11.4% (Schedule R).

9 Exhibits DOD-307 and DOD-308 show that somewhat smaller increases to the
10 classes that are below cost would be required to move 50% and 25%, respectively, of
11 the way to cost of service.

12 **RECOMMENDED ALLOCATION OF ANY INCREASE**

13 Q. WHAT IS YOUR RECOMMENDATION FOR THE ALLOCATION OF ANY
14 INCREASE THAT HECO MAY RECEIVE OVER THE CURRENTLY EFFECTIVE
15 RATES?

16 A. I recommend that the Commission direct HECO to implement any approved rate
17 increase by allocating the revenue increase among customer classes with the
18 objective of reducing the existing interclass subsidies. Increases for various degrees
19 of movement toward cost of service at HECO's requested revenue requirement are
20 shown on Exhibits DOD-306 through DOD-308.

RATE DESIGN ISSUES

Schedule DS – Large Power Directly Served Load

Q. HAS HECO PROPOSED TO OFFER A NEW RATE SCHEDULE FOR CERTAIN LARGE POWER CUSTOMERS?

A. Yes. The DS rate schedule explicitly recognizes the different character of service involved when customers receive service directly from a substation. This schedule explicitly and separately recognizes that there is a certain group of customers that were formerly served on Rate Schedule PP, who receive the substation discount, because they have service characteristics different from the other customers served on Schedule PP. Namely, the directly served customers do not require the investment in much of the primary distribution system.

As explained in the testimony of HECO witness Young (T-22 at page 33), when HECO reviewed these customers and their characteristics, it found that all of the customers currently served on Schedule PT had the same characteristics. Accordingly, the proposed new DS rate combines the current Schedule PT customers with the substation-served primary customers from Rate PP.

Q. HAVE YOU REVIEWED THE DESIGN OF THIS PROPOSED DS RATE?

A. Yes, I have. I believe it appropriately takes into consideration the characteristics of these customers, and is consistent with the agreement which HECO made with its customers in its previous rate case.

While I believe the offering of the rate, its availability and its structure is appropriate, as noted elsewhere I believe that the amount of revenue which HECO has assigned to this rate is higher than it should be.

Design of Schedules DS and P

Q. HAVE YOU GENERALLY REVIEWED HOW HECO PROPOSES TO SET THE CHARGES WITHIN RATES DS AND P IN ORDER TO ACHIEVE ITS PROPOSED REVENUE TARGET?

A. Yes. HECO has adjusted the charges within these rates in a manner that moves both demand charges and energy charges toward the unit costs of demand and energy, respectively, as revealed in its cost of service studies. The overall basic design of the rate schedules has been retained.

Q. DO YOU AGREE WITH HECO'S ADJUSTMENTS WITHIN THESE RATE SCHEDULES?

A. Yes. While I disagree with the amount of revenue assigned to these schedules, I believe that the general design of the rates which HECO has followed is appropriate. By moving the demand and energy charges closer to their respective unit costs, the price signals given to customers are improved and equity also is improved within the rates as customers with different characteristics will be more appropriately priced in relation to the costs which they impose on the system.

1 **Power Factor Cost Study**

2 Q. IN A STIPULATION IN ITS PREVIOUS RATE CASE, DID HECO AGREE TO
3 PRESENT A STUDY OF THE COSTS OF PROVIDING REACTIVE POWER,
4 SOMETIMES REFERRED TO AS VARHR OR VARS?

5 A. Yes. As a result of issues raised by the Office of Consumer Advocate concerning
6 charges for power factor correction, HECO agreed to prepare and present in this
7 case an appropriate study.

8 Q. HAVE YOU REVIEWED HECO'S STUDY?

9 A. Yes.

10 Q. DO YOU AGREE THAT HECO'S STUDY HAS APPROPRIATELY DETERMINED
11 THE COST OF PROVIDING POWER FACTOR CORRECTION?

12 A. No, I do not. There are several problems with HECO's study. First, the study looked
13 at the investment cost of all capacitor banks on the HECO system, but only kVARs
14 associated with Schedules J, PP, PS and PT were considered in the study, despite
15 the fact that kVARs are associated with every tariff schedule. Apparently, this was
16 done because only Schedules J, PP, PS and PT have explicit charges for power
17 factor. Dividing the kVARs from just these schedules into the annual revenue
18 requirement of all capacitor banks on the system produces a totally meaningless
19 number, because the effect of the remaining schedules is not considered in the
20 results.

21 Second, HECO adds to these amounts the annual fuel and purchased power
22 revenue requirement, which it again divides by only the kVARs from Schedules J, PP,

1 PS and PT. Again, this is a meaningless number. It is meaningless regardless of the
2 calculation specifics because utilities do not incur fuel and purchased power
3 requirements to generate reactive power. Fuel is consumed to produce kW and
4 kWhs, and not reactive power. At the generation level, reactive power is produced as
5 a function of the amount of the direct current (DC) in a synchronous generator's
6 excitation system used to control the generator's terminal voltage. Reactive power
7 production does not consume fuel.

8 Furthermore, HECO's attempted justification for its conclusions is not even
9 based on the results of its study, but based on a comparison of the results of its
10 calculations over a three-year period. Regardless of the quality of HECO's
11 calculations, this comparison over time reveals nothing about the cost of producing
12 reactive power to accomplish power factor correction.

13 **Q. SHOULD THE COMMISSION RELY UPON THE RESULTS OF HECO'S STUDY IN**
14 **THIS CASE?**

15 **A.** No. HECO's study cannot be relied upon. While it may be appropriate to change the
16 charges for power factor corrections, HECO has not presented any evidence to
17 support changing those values. It is my recommendation that no changes be made
18 at this time.

1 **Energy Cost Adjustment Clause**

2 **Q. WHAT CHANGES DOES HECO PROPOSE TO THE ENERGY COST**
3 **ADJUSTMENT CLAUSE (ECAC)?**

4 A. HECO proposes changes generally to: (1) conform the applicability clause to the new
5 structure of the tariffs, (2) change the base of the fuel and purchased power costs to
6 current levels, and (3) change the generation efficiency factors to reflect the test year
7 values.

8 **Q. DO YOU HAVE AN OBJECTION TO ANY OF THESE MODIFICATIONS?**

9 A. No. I do not object, provided that the efficiency factors proposed by HECO are
10 updated to conform to the final values as a result of the revenue requirement
11 determination in this case; and also provided that the base points for fuel and
12 purchased power are updated to the final values used in establishing rates in this
13 case.

14 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

15 A. Yes, it does.

Qualifications of Maurice Brubaker

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. Maurice Brubaker. My business address is 16690 Swingley Ridge Road, Suite 140,
3 Chesterfield, MO 63017.

4 **Q. PLEASE STATE YOUR OCCUPATION.**

5 A. I am a consultant in the field of public utility regulation and President of the firm of
6 Brubaker & Associates, Inc. (BAI), energy, economic and regulatory consultants.

7 **Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND**
8 **EXPERIENCE.**

9 A. I was graduated from the University of Missouri in 1965, with a Bachelor's Degree in
10 Electrical Engineering. Subsequent to graduation I was employed by the Utilities
11 Section of the Engineering and Technology Division of Esso Research and
12 Engineering Corporation of Morristown, New Jersey, a subsidiary of Standard Oil of
13 New Jersey.

14 In the Fall of 1965, I enrolled in the Graduate School of Business at
15 Washington University in St. Louis, Missouri. I was graduated in June of 1967 with
16 the Degree of Master of Business Administration. My major field was finance.

17 From March of 1966 until March of 1970, I was employed by Emerson Electric
18 Company in St. Louis. During this time I pursued the Degree of Master of Science in
19 Engineering at Washington University, which I received in June, 1970.

20 In March of 1970, I joined the firm of Drazen Associates, Inc., of St. Louis,
21 Missouri. Since that time I have been engaged in the preparation of numerous

1 studies relating to electric, gas, and water utilities. These studies have included
2 analyses of the cost to serve various types of customers, the design of rates for utility
3 services, cost forecasts, cogeneration rates and determinations of rate base and
4 operating income. I have also addressed utility resource planning principles and
5 plans, reviewed capacity additions to determine whether or not they were used and
6 useful, addressed demand-side management issues independently and as part of
7 least cost planning, and have reviewed utility determinations of the need for capacity
8 additions and/or purchased power to determine the consistency of such plans with
9 least cost planning principles. I have also testified about the prudence of the actions
10 undertaken by utilities to meet the needs of their customers in the wholesale power
11 markets and have recommended disallowances of costs where such actions were
12 deemed imprudent.

13 I have testified before the Federal Energy Regulatory Commission (FERC),
14 various courts and legislatures, and the state regulatory commissions of Alabama,
15 Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia,
16 Guam, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Missouri,
17 Nevada, New Jersey, New Mexico, New York, North Carolina, Ohio, Pennsylvania,
18 Rhode Island, South Carolina, South Dakota, Texas, Utah, Virginia, West Virginia,
19 Wisconsin and Wyoming.

20 The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and
21 assumed the utility rate and economic consulting activities of Drazen Associates, Inc.,
22 founded in 1937. In April, 1995 the firm of Brubaker & Associates, Inc. was formed. It
23 includes most of the former DBA principals and staff. Our staff includes consultants

1 with backgrounds in accounting, engineering, economics, mathematics, computer
2 science and business.

3 Brubaker & Associates, Inc. and its predecessor firm has participated in over
4 700 major utility rate and other cases and statewide generic investigations before
5 utility regulatory commissions in 40 states, involving electric, gas, water, and steam
6 rates and other issues. Cases in which the firm has been involved have included
7 more than 80 of the 100 largest electric utilities and over 30 gas distribution
8 companies and pipelines.

9 An increasing portion of the firm's activities is concentrated in the areas of
10 competitive procurement. While the firm has always assisted its clients in negotiating
11 contracts for utility services in the regulated environment, increasingly there are
12 opportunities for certain customers to acquire power on a competitive basis from a
13 supplier other than its traditional electric utility. The firm assists clients in identifying
14 and evaluating purchased power options, conducts RFPs and negotiates with
15 suppliers for the acquisition and delivery of supplies. We have prepared option
16 studies and/or conducted RFPs for competitive acquisition of power supply for
17 industrial and other end-use customers throughout the United States and in Canada,
18 involving total needs in excess of 3,000 megawatts. The firm is also an associate
19 member of the Electric Reliability Council of Texas and a licensed electricity
20 aggregator in the State of Texas.

21 In addition to our main office in St. Louis, the firm has branch offices in
22 Phoenix, Arizona and Corpus Christi, Texas.

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HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST YEAR 2009

Proposed Revenue Increase

Line	Rate Class	Revenues Under Currently Effective Rates (000) (1)	<u>Proposed Increase</u>		Revenues at Proposed Rates (000)
			Amount (000) (2)	Percent (3)	
1	Schedule R	\$ 560,709.1	\$ 30,093.0	5.37%	\$ 590,802.1
2	Schedule G	111,242.0	5,969.3	5.37%	117,211.3
3	Schedule J	509,668.3	27,351.0	5.37%	537,019.3
4	Schedule DS	260,144.9	13,961.1	5.37%	274,106.0
5	Schedule P	410,467.1	22,028.1	5.37%	432,495.2
6	Schedule F	<u>9,519.2</u>	<u>510.9</u>	5.37%	<u>10,030.1</u>
7	Total Sales Revenue	1,861,750.6	99,913.4	5.37%	1,961,664.0
8	Other Operating Revenue	<u>5,102.0</u>	<u>122.0</u>	2.39%	<u>5,224.0</u>
9	Total	\$ 1,866,852.6	\$ 100,035.4	5.36%	\$ 1,966,888.0

Source:

Rate Case Update
HECO T-22, Attachment 1, page 4 of 39
Current Effective Rates with Minimum System

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST YEAR 2009

**Summary of Class Rates of Return, Indexes
and Subsidies at Currently Effective Rates**

Line	Rate Class	Operating Revenues (000) (1)	Operating Expenses (000) (2)	Operating Income (000) (3)	Rate Base (000) (4)	Rate of Return (5)	Index ¹ (6)	Subsidy ² (000) (7)
1	Schedule R	\$ 564,087.5	\$ 550,560.1	\$ 13,527.4	\$ 558,179.2	2.42%	50	\$ (24,469.9)
2	Schedule G	111,678.8	102,386.2	9,292.6	112,918.8	8.23%	169	6,836.1
3	Schedule J	510,453.3	492,914.6	17,538.7	383,391.1	4.57%	94	(1,980.6)
4	Schedule DS	260,291.3	252,319.3	7,972.0	117,497.3	6.78%	140	4,061.8
5	Schedule P	410,795.5	390,741.4	20,054.1	230,901.7	8.69%	179	15,870.3
6	Schedule F	<u>9,546.3</u>	<u>9,308.4</u>	<u>237.9</u>	<u>8,528.2</u>	2.79%	57	<u>(317.7)</u>
7	Total	\$ 1,866,852.7	\$ 1,798,230.0	\$ 68,622.7	\$ 1,411,416.3	4.86%	100	\$ 0.0

Notes:

¹ An index below 100 means a class is below the system rate of return and would require an above average percent increase. An index above 100 means a class is above the system rate of return and would require a below average percent increase.

² A negative number indicates the amount of subsidy a class is receiving.
A positive number indicates the amount of subsidy a class is providing.

Source:

Rate Case Update
HECO T-22, Attachment 2, page 53 of 70
Current Effective Rates with Minimum System

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST YEAR 2009

**Summary of Class Rates of Return, Indexes
and Subsidies at Proposed Rates**

Line	Rate Class	Operating Revenues (000) (1)	Operating Expenses (000) (2)	Operating Income (000) (3)	Rate Base (000) (4)	Rate of Return (5)	Index ¹ (6)	Subsidy ² (000) (7)	Increase in Expenses
1	Schedule R	\$ 594,276.3	\$ 563,973.7	\$ 30,302.6	\$ 557,904.7	5.43%	62	\$ (33,883.9)	\$ 13,413.6
2	Schedule G	117,660.0	105,041.4	12,618.6	112,865.1	11.18%	127	4,809.9	2,655.2
3	Schedule J	537,816.8	505,054.1	32,762.7	383,145.6	8.55%	97	(1,782.7)	12,139.5
4	Schedule DS	274,252.4	258,510.0	15,742.4	117,372.5	13.41%	152	9,711.8	6,190.7
5	Schedule P	432,824.5	400,509.9	32,314.6	230,704.6	14.01%	159	21,555.5	9,768.5
6	Schedule F	<u>10,057.9</u>	<u>9,535.3</u>	<u>522.6</u>	<u>8,524.3</u>	6.13%	70	<u>(410.6)</u>	<u>226.9</u>
7	Total	\$ 1,966,887.9	\$ 1,842,624.5	\$ 124,263.4	\$ 1,410,516.8	8.81%	100	\$ (0.0)	\$ 44,394.5

Notes:

¹ An index below 100 means a class is below the system rate of return and would require an above average percent increase. An index above 100 means a class is above the system rate of return and would require a below average percent increase.

² A negative number indicates the amount of subsidy a class is receiving.
A positive number indicates the amount of subsidy a class is providing.

Source:

Rate Case Update
HECO T-22, Attachment 2, pages 54 and 63 of 70
Current Effective Rates with Minimum System

**HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST YEAR 2009**

**Comparison of Subsidies at
Currently Effective and Proposed Rates**

Line	Rate Class	Subsidy at	Subsidy at	Change in Subsidy	
		Currently	Proposed	Amount	Direction of
		Effective	Rates	(000)	Change
		Rates	Rates		
		(000) *	(000) *	(000)	
		(1)	(2)	(3)	(4)
1	Schedule R	\$ (24,469.9)	\$ (33,883.9)	\$ 9,414.0	Further Below Cost
2	Schedule G	6,836.1	4,809.9	2,026.3	Closer to Cost
3	Schedule J	(1,980.6)	(1,782.7)	197.9	Closer to Cost
4	Schedule DS	4,061.8	9,711.8	5,650.1	Further Above Cost
5	Schedule P	15,870.3	21,555.5	5,685.2	Further Above Cost
6	Schedule F	<u>(317.7)</u>	<u>(410.6)</u>	92.8	Further Below Cost
7	Total	\$ 0.0	\$ (0.0)		

* A negative number indicates the amount of subsidy a class is receiving.
A positive number indicates the amount of subsidy a class is providing.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST YEAR 2009

**Increase Over Currently Effective Revenues
to Reduce Subsidies by 100%**

<u>Line</u>	<u>Rate Class</u>	Currently Effective Revenues (000) (1)	<u>Required Increase</u>	
			Amount (000) (2)	Percent (3)
1	Schedule R	\$ 564,087.5	\$ 64,072.7	11.36%
2	Schedule G	111,678.8	1,171.3	1.05%
3	Schedule J	510,453.3	29,146.2	5.71%
4	Schedule DS	260,291.3	4,249.3	1.63%
5	Schedule P	410,795.5	473.5	0.12%
6	Schedule F	<u>9,546.3</u>	<u>922.2</u>	9.66%
7	Total	\$ 1,866,852.7	\$ 100,035.2	5.36%

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST YEAR 2009

**Increase Over Currently Effective Revenues
to Reduce Subsidies by 50%**

<u>Line</u>	<u>Rate Class</u>	Currently Effective Revenues (000) (1)	<u>Required Increase</u>	
			Amount (000) (2)	Percent (3)
1	Schedule R	\$ 564,087.5	\$ 51,837.7	9.19%
2	Schedule G	111,678.8	4,589.4	4.11%
3	Schedule J	510,453.3	28,155.9	5.52%
4	Schedule DS	260,291.3	6,280.2	2.41%
5	Schedule P	410,795.5	8,408.7	2.05%
6	Schedule F	<u>9,546.3</u>	<u>763.3</u>	8.00%
7	Total	\$ 1,866,852.7	\$ 100,035.2	5.36%

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083, TEST YEAR 2009

**Increase Over Currently Effective Revenues
to Reduce Subsidies by 25%**

<u>Line</u>	<u>Rate Class</u>	Currently Effective Revenues	<u>Required Increase</u>	
		(000) (1)	Amount (000) (2)	Percent (3)
1	Schedule R	\$ 564,087.5	\$ 45,720.3	8.11%
2	Schedule G	111,678.8	6,298.4	5.64%
3	Schedule J	510,453.3	27,660.8	5.42%
4	Schedule DS	260,291.3	7,295.6	2.80%
5	Schedule P	410,795.5	12,376.3	3.01%
6	Schedule F	<u>9,546.3</u>	<u>683.9</u>	7.16%
7	Total	\$ 1,866,852.7	\$ 100,035.2	5.36%

CERTIFICATE OF SERVICE

I hereby certify that one copy of the foregoing document was duly served upon the following parties, by personal service, hand-delivery, and/or U.S. mail, postage prepaid, and properly addressed pursuant to HAR sec. 6-61-21(d).

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Executive Director
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